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COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY **CASE NO. PUE960036**

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COMMONWEALTH OF VIRGINIA

At the relation of the

STATE CORPORATION COMMISSION **CASE NO. PUE960296**

Ex Parte: Investigation of Electric Utility Industry Restructuring -- Virginia Electric and Power Company

Direct Testimony of Jeffry Pollock

INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri, 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy, economic and regulatory consultant and a principal in the firm of BAI (Brubaker & Associates, Inc.)

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. More details are provided in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A I am testifying on behalf of the Virginia Committee for Fair Utility Rates ("VCFUR"). The VCFUR group is comprised of 19 companies that represent a broad array of industries. VCFUR members are customers of Virginia Electric and Power Company ("Virginia Power") and purchase electricity primarily on Schedule GS-4.

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A I shall address Virginia Power's proposed Alternative Regulatory Plan (ARP), the quantification and recovery of "transition" costs, the proposed Transition Cost Charge (TCC), the unbundling of Virginia Power's present tariffs into discrete components, interclass revenue allocation and real time pricing (RTP).

1. ALTERNATIVE REGULATORY PLAN

Q PLEASE DESCRIBE VIRGINIA POWER'S PROPOSED ALTERNATIVE REGULATORY PLAN.

A According to Virginia Power, its Alternative Regulatory Plan (ARP) is a mechanism to enable Virginia Power to reduce its costs and to prepare for competition. The proposal defines two discrete "transition" periods. As discussed later, the nature of the transition is unclear.

The first "transition" period would commence on March 1, 1997 and continue until December 31, 2002, or when retail competition is authorized in Virginia. During this almost six-year period, base rates would remain frozen at present levels. Changes in fuel costs, however, would continue to be passed through the Fuel Cost Adjustment (FCA) as presently done. Earnings would be allowed to vary within a bandwidth defined by the earned return on equity (ROE). The earned ROE would include both regulated and unregulated businesses. Earnings in excess of an 11.5% ROE and up to 13% would be used to write down approximately $500 million of claimed regulatory assets (the amount claimed by Virginia Power that would otherwise exist at the end of the rate freeze). If Virginia Power were able to mitigate other transition costs not claimed by Virginia Power as regulatory assets, then funds from this bandwidth would be used to mitigate those costs. Earnings above the upper limit of the bandwidth (13%) would be shared equally between customers and shareholders.

The next "transition" period would commence immediately after the end of the rate freeze or when retail competition is authorized in Virginia, whichever occurs sooner. This second period would last seven years. During this seven-year period, Virginia Power would implement a TCC. The purpose of the TCC, according to the Company, would be to permit the Company an opportunity to recover all remaining *transition* costs, except nuclear decommissioning costs. The nuclear decommissioning costs would continue to be recovered in a separate charge over the projected useful lives of the nuclear units, though Virginia Power proposes to accelerate their recovery in this case. To assure recovery of all transition costs, Virginia Power asks the Commission to approve the TCC in concept *in this proceeding*, or up to six years prior to the effective date of the TCC. I shall address the TCC in Part 2 of my testimony.

Q **HOW DOES VIRGINIA POWER DEFINE TRANSITION COSTS?**

A Virginia Power defines *transition* costs as consisting of plant investment, regulatory assets (expenditures that are authorized to be recovered over a number of years rather than when incurred), and power purchases from non-utility generation (NUG), the costs of which will not be fully recoverable in a competitive generation/bulk power market.[1]

Q **HAS VIRGINIA POWER ESTIMATED THE AMOUNT OF TRANSITION COSTS?**

[1] Rigsby Direct Testimony, Page 11.

A Yes. The Company estimates that it will incur total system-wide *transition* costs of up to $3.2 billion.[2] According to the Company, this is equal to $2.5 billion on a Virginia Jurisdictional basis. Of this amount, the NUG contracts would account for $2.3 billion. It should be noted that these estimates are only for illustrative purposes. VCFUR witness Iverson provides an analysis that uses more appropriate assumptions and that shows the high degree of sensitivity of the Company's estimate to key assumptions.

Q DOES VIRGINIA POWER HAVE ANY TRANSITION COSTS TODAY?

A No. Virginia Power's nuclear plants and NUG contract costs, for example, would be more accurately described as *potentially stranded* by customer choice because the investment and expenses are currently subject to regulation and are not subject to market forces. Customer choice has not been authorized in Virginia.

Q DOES VIRGINIA POWER'S ESTIMATE OF TRANSITION COSTS MAKE ANY DISTINCTION BETWEEN COSTS THAT MAY NOT BE RECOVERABLE SOLELY DUE TO CUSTOMER CHOICE AND OTHER COSTS THAT MAY BE UNRECOVERABLE FOR REASONS UNRELATED TO COMPETITION?

A No. Virginia Power experiences diminished revenues and returns for a variety of reasons unrelated to customer choice, such as mild weather, economic down-turns, demand-side management and energy conservation measures, plant closings,

[2]Transition Cost Report, Page 12.

relocations, competition with natural gas, self-generation, and various special rates for cogeneration deferral, economic development and load retention. Because Virginia Power currently faces these risks, and because the current regulatory and legal environment currently compensates Virginia Power for these risks, these risks are unrelated to the impact of retail competition.

Q IS VIRGINIA POWER'S ALTERNATIVE REGULATORY PLAN A TRANSITION TO RETAIL COMPETITION?

A No. Virginia Power's Plan does not propose retail competition. The Plan requests "full recovery" of all *transition* costs without recommending retail competition.[3] Thus, Virginia Power's Plan cannot fairly be described as a "transition" because Virginia Power has failed to include the end-point of such a claimed "transition"—retail customer choice. Virginia Power has not made any commitment to offer retail customer choice at the end of the "freeze." Thus, while the Plan is subject to many criticisms, which I discuss further in my testimony, at the very outset , it is important to emphasize that the Plan is in no way a "transition" to retail competition.

Q IF IT IS NOT A TRANSITION TO RETAIL COMPETITION, THEN WHY IS VIRGINIA POWER PROPOSING AN ALTERNATIVE REGULATORY PLAN AT THIS TIME?

A In requesting approval of its ARP, the Company states that it needs:

[3] See Virginia Power's Response to Question No. 177 included in the Fifth Set of Interrogatories from the Office of the Attorney General, where the Company states: "It is a plan to recover costs first, with anything remaining after those costs have been recovered to the extent specified to be split between customers and shareholders. This is entirely consistent with full recovery of the previously unrecovered components of cost of service that make up the transition costs in this case."

> "... greater flexibility than exists under traditional rate regulation to ensure that the transition process treats all stakeholders fairly and enables the Company to remain financially viable by providing it with the opportunity to recover costs that were prudently incurred in the discharge of its public service mandate.
>
> ... This proposal would thus provide the flexibility Virginia Power needs to make an orderly transition to competition without impairing the Company's ability to meet its public service obligations reliably, efficiently and economically."[4]

Q **CAN APPROVAL OF THE ALTERNATIVE REGULATORY PLAN BE JUSTIFIED ON THE ABOVE-STATED PREMISES?**

A No. It is premature to provide now for an orderly transition when the evidence is so speculative that Virginia Power will sustain any adverse impact from retail competition. For example, Ms. Iverson's testimony demonstrates how Virginia Power's estimate of transition costs is highly sensitive to certain questionable assumptions, and how using different, but realistic, assumptions suggests the existence of *\$2.7 billion of transition benefits*, instead of *\$2.5 billion of transition costs*, for Virginia Jurisdictional customers. In other words, with those changes in assumptions, Virginia Power would be a competitive provider of generation services if all customers could choose their supplier(s).

The ARP also cannot be justified as a means of recovering generation-related regulatory assets because, according to Mr. Dooley's testimony, there are few such related assets that remain to be recovered. What is abundantly clear about the ARP is that it would be a dramatic departure from cost of service

[4] Virginia Power Application, Executive Overview, Pages 1 and 2.

ratemaking practices. As discussed later, this Plan fails to equitably balance the interests of Virginia Power's shareholders and its customers. Although it would provide Virginia Power with an opportunity to prepare for competition, nothing in the proposal would enable Virginia Power's customers either to prepare for, or benefit from, competition.

Q **IS IT POSSIBLE TO DETERMINE, IN THIS PROCEEDING, HOW VIRGINIA POWER MIGHT BE IMPACTED BY RETAIL COMPETITION?**

A No. There is no date certain for retail competition in Virginia. Many other key factors simply are unknown. We do not yet know whether all customers will immediately switch suppliers (i.e., a "flash cut" to customer choice), how a competitive market will be structured, whether prices will be transparent, whether incumbent utilities will remain vertically integrated and retain ownership of their existing generation resources, whether barriers to entry will prevent alternative generation suppliers and sales merchants from providing competitive services to end users–thereby keeping prices high, or the extent that Virginia Power can further mitigate costs, particularly its NUG resource costs.

Unless we know much more about these critical parameters, it would be premature to draw the kinds of conclusions that Virginia Power asks us to draw about the impact of retail competition on Virginia Power.

The Alternative Regulatory Plan Would Be A Dramatic Departure From Cost Of Service Ratemaking Practices

Q WOULD THE ALTERNATIVE REGULATORY PLAN REPRESENT A DRAMATIC DEPARTURE FROM TRADITIONAL COST OF SERVICE REGULATION?

A Yes. According to VCFUR witness Dooley, Virginia Power currently is over-earning. With continued depreciation and the phase-down of certain purchased power contracts, Virginia Power is likely to continue to over-earn, unless rates are adjusted in this proceeding.

Thus, under the ARP, rates would be frozen at a level significantly above Virginia Power's actual cost of providing service. Further, these above-cost of service rates would be maintained for almost six years (from March 1997 though December 2002). Customers, thus, would be forced to relinquish hundreds of millions of dollars of rate reductions over the next five to six years in return for a promise of lower rates in year seven.[5] If traditional ratemaking practices were to continue, rates would be reduced to reflect the Company's lower costs. Furthermore, even Virginia Power's vague promises of lower rates in the future may be offset by the proposed "safety valve" that would permit a rate increase under certain circumstances.[6]

[5]Wright Direct Testimony, Page 12.

[6]Rigsby Direct Testimony, Page 39.

Q SHOULD MAJOR CHANGES IN RATEMAKING PRACTICES BE PREMISED ON SPECULATION ABOUT THE POTENTIAL IMPACT OF RETAIL COMPETITION?

A No. It would be inadvisable to implement dramatic changes in ratemaking practices, such as Virginia Power's ARP, based on premature speculation about the potential impact (or lack thereof) of retail competition. It has not been shown that any extraordinary treatment is needed to provide "an orderly transition to competition" or to prevent "impairing the Company's ability to meet its public service obligations reliably, efficiently and economically."

The Alternative Regulatory Plan Fails To Equitably Balance Customer And Shareholder Interests

Q DOES THE ALTERNATIVE REGULATORY PLAN PROVIDE AN EQUITABLE BALANCING OF INTEREST BETWEEN CUSTOMERS AND VIRGINIA POWER'S SHAREHOLDERS?

A No. The Plan, as proposed by Virginia Power, provides few, if any, customer benefits. On the contrary, it is significantly slanted in favor of shareholders through, for example, its *regressive* earnings sharing mechanism, which is discussed below.

Further, accelerating the recovery of *potentially stranded* costs, as the plan contemplates, should be justification alone to award a lower ROE. This extraordinary proposal would enable the Company to reduce future business and operating risks. The Company, however, has applied a "business-as-usual" approach by recommending the high end of its authorized regulatory return (i.e., 11.5%). Then, the Company allows its shareholders immediately to benefit by cost reduction efforts that would result in earnings in excess of a normal regulatory return.[7]

Q HOW WILL VIRGINIA POWER'S SHAREHOLDERS BE THE PRIMARY BENEFICIARIES OF THE PROPOSED ALTERNATIVE REGULATORY PLAN?

A Shareholders would have an opportunity to receive their ***full*** ROE and then some. First, all excess earnings above an 11.5% ROE up to a 13% ROE would be used to accelerate recovery of claimed generation-related regulatory assets. As proposed, this means that shareholders would fully recover any unrecovered regulatory assets. (Of course, since Mr. Dooley's testimony shows that the Company has overstated dramatically its claims regarding the existence of regulatory assets, the Company's proposal for full retention of excess earnings between 11.5% and 13.0% would leave the Company with a generous earnings cushion.) Second, 50% of any excess earnings above a 13% ROE would be retained by shareholders. In other words, 100% of the initial benefits from cost reduction efforts, which would raise Virginia Power's earned ROE above 11.5%, would be used to benefit shareholders. At the end of the proposed rate freeze, the Company's costs will be lower and its competitive position enhanced. Rather than providing "an opportunity for customers and shareholders to share in exceptionally strong financial performance," only when earnings rise to above the uppermost bandwidth (i.e., a 13% ROE) would customers see any reduction to their rate levels.

[7] Rigsby Direct Testimony, Pages 32-34.

As an indication of how unbalanced this proposal really is, the Company anticipates that customers would realize only **$*************** of benefits during the five years, while shareholders would receive **$*************** in benefits through the sharing mechanism <u>together</u> with **$*************** of stranded cost recovery, plus **$************** return on the regulatory assets subject to accelerated recovery, for a total of **$*************** of shareholder benefits.[8] (Immediately before the filing of this testimony, the Company notified us that it had modified its projections for a portion of the "freeze" period. The late notice did not afford any opportunity to update these totals.) **[********** INDICATES DELETION OF INFORMATION ALLEGED TO BE COMMERCIALLY SENSITIVE.]**

Q **BUT WON'T THE ELIMINATION OF REGULATORY ASSETS ALSO BENEFIT CUSTOMERS?**

A Any future benefit to customers is purely speculative and, at best, indirect. That is, customers may benefit indirectly in the future from reducing *potentially stranded* costs today, but this benefit is only speculative. The magnitude of Virginia Power's *transition* costs, if any, is exceedingly uncertain at this time. Again, there is no date certain for retail access to commence. Many issues, especially market power and market structure issues, have not been addressed, let alone resolved. More fundamentally, the Company assumes that customers would regard the writing down

[8] Response to Staff's First Set of Interrogatories, Question No. 120 **(Commercially Sensitive Information).** The Company's estimates are stated on a total, system-wide basis.

of *potentially stranded* costs as a benefit. In other words, the assumption is that it is beneficial to customers to forgo hundreds of millions of dollars of rate decreases in order to improve Virginia Power's competitive position. There is no such obligation.

Q AREN'T CUSTOMERS OBLIGATED UNDER A "REGULATORY COMPACT" TO PROVIDE VIRGINIA POWER A REASONABLE OPPORTUNITY TO FULLY RECOVER ALL PRUDENTLY INCURRED COSTS?

A No such regulatory compact ever has been committed to writing, either in Virginia or elsewhere in the U.S. Even Dr. Wright characterizes the so-called regulatory compact as an *implicit bargain*.[9] Traditional regulation, which provided a *surrogate* for competition, has granted utilities the *opportunity* to earn a reasonable return on their prudently incurred, used and useful investments. Further, I disagree with Dr. Wright's contention that the so-called compact requires consumers to bear all prudently incurred costs.[10] Regulation has never provided a *guarantee* that shareholders would realize such returns under any and all circumstances. In fact, regulators always have established utility rates of return in a manner that is designed to compensate utilities for the business risks that they incur. There is no legitimate basis to claim that the transition to retail competition should somehow create a ratepayer obligation to fully insulate utilities from any loss in revenues due to changes in the business environment. There is no mandate that all prudently

[9]Wright Direct Testimony, Page 5.

[10]Id. at Page 6.

incurred costs be fully recovered by a date certain. Further, a competitive market will allow utilities an opportunity to recover their costs and earn returns that not capped by price regulation.

Q. BUT DOESN'T THE ONSET OF COMPETITION REPRESENT SUCH A CHANGE IN CIRCUMSTANCES THAT, IN FAIRNESS, UTILITY INVESTORS SHOULD BE PERMITTED FULL RECOVERY OF, AND A FULL RETURN ON, ALL PRUDENTLY INCURRED COSTS?

A. No. There never has been such a "compact," as I discussed above. Further, the changes in the electric industry that will enable real competition to replace the regulatory surrogate at the generation and merchant levels did not occur overnight. The evolutionary process has been ongoing since the enactment of the Public Utility Regulatory Policies Act, in 1978, which created new opportunities for non-utility generators (NUGS). It has been sustained by continuing improvements in turbine technology, increasing competition in other formerly regulated industries (e.g. natural gas, long-distance telephone, rail, and trucking), the availability of abundant, low-cost natural gas and the Energy Policy Act of 1992 -- which expanded supply competition by allowing utilities to form "exempt wholesale generators" to market power at wholesale and enabled the FERC to order wholesale wheeling. Utility investors have been on notice for years that competition is coming to the electric industry, and today it is almost impossible to pick up any literature related to the electric industry without the subject being mentioned. The business risks associated with competition have been taken into account by the market for years.

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1. Alternative Regulatory Plan

Q VIRGINIA POWER STATES THAT ALTERNATIVE FORMS OF REGULATION HAVE "...ALREADY BEEN RECOGNIZED IN LEGISLATION ENACTED BY THE VIRGINIA GENERAL ASSEMBLY." DOES THE COMPANY'S PLAN MEET THE REQUIREMENTS OF THE ENACTED LEGISLATION?

A No, it does. In Va. Code, § 56-235.2 provides:

> "C. The Commission shall, before approving ... alternative regulatory plans under subsections A and B, assure that such action (I) protects the public interest, (ii) will not unreasonably prejudice or disadvantage any customers or class of customers, and (iii) will not jeopardize the continuation of reliable electric service.

Since the Company is requesting full recovery of specific transition costs over the five-year period, and full recovery of transition costs is not in the public interest, the Company's plan does not protect the public interest. Furthermore, the Plan will disadvantage all customer classes since it does not provide an equitable sharing of benefits between shareholders and customers. Finally, the Company has not proposed any measurable standards to benchmark service quality, reliability and safety. Without such benchmarks, and the necessary tools to enforce them, it will be impossible for the Commission to ensure that the Company is cutting costs, rather than cutting corners.

The Transition To Customer Choice And Protection Against <u>Potential Market Power Abuses Should Be The Focus, Not ARP</u>

Q ARE THERE ANY OTHER REASONS WHY THE COMMISSION SHOULD REJECT THE ALTERNATIVE REGULATORY PLAN?

A Yes. First, the proposed earnings sharing mechanism is *regressive*. That is, Virginia Power shareholders receive all of the initial benefits of cost reduction efforts, including full, accelerated recovery of regulatory assets. Second, the ARP represents a piece-meal change relative to the present rate base/rate of return form of price regulation. Rather than simplify matters, it is an unnecessary distraction in moving toward a customer choice environment. Finally, as discussed previously, recovery of *any* transition costs is premature. Allowing recovery to commence without concrete evidence of the existence, impact and need to recover transition costs from customers could prevent the Commission from adopting policies to foster a more competitive future.

Q **WHAT IS MEANT BY A REGRESSIVE EARNINGS SHARING MECHANISM?**

A A *regressive* sharing mechanism permits the utility to retain the first level of savings, but shares the benefits only after its earnings exceed the upper bandwidth, in this case, 13.0% ROE. Looking at this another way, it is apparent that the Company is using its share of excess earnings to enhance shareholder wealth rather than to lower rates. This contrasts with a *progressive* sharing mechanism in which customers receive all of the first level of savings but then gradually relinquish benefits to shareholders as the earned ROE exceeds the upper bandwidth. The Company's proposed regressive sharing mechanism is reason alone for the Company's proposal to be rejected.

Q HOW WOULD THE ALTERNATIVE REGULATORY PLAN BE A DISTRACTION FROM THE TRANSITION TO CUSTOMER CHOICE?

A An effective ARP would require close Commission monitoring of Virginia Power's performance in other key areas, including service quality, reliability, responsiveness to outages and requests for new installations and safety. Appropriate monitoring means first developing standards to measure performance in these (and possibly other) key areas and then providing the tools so that the standards can be enforced by this Commission. The Company has not proposed any such standards in this proceeding. It could take considerable time and effort, moreover, to develop them and even more time to implement and enforce them.

Q WOULD THE EFFORT TO DEVELOP SERVICE PERFORMANCE STANDARDS IN CONNECTION WITH AN ALTERNATIVE REGULATORY PLAN BE A GOOD USE OF THE COMMISSION'S TIME AND RESOURCES?

A No. In my opinion, it would not be worth the time and effort to develop meaningful performance standards when there is a preferable and more effective alternative. That alternative is competition. With competition, and specifically I mean customer choice, the market will provide the necessary discipline to ensure that customers receive the quality services that they demand at costs they deem reasonable and to generate the returns demanded by shareholders. If a supplier fails to perform, then the customer is free to choose a different supplier who will provide the service demanded by the customer. There is nothing more powerful than the threat of losing business to motivate a supplier to implement strict performance standards.

Further, considerable resources will have to be expended to successfully complete the transition from regulation to retail customer choice in a timely fashion. Thus, the Commission should focus its resources on the transition to customer choice, not on making piece-meal changes in regulation.

Q WHAT WOULD BE THE CONSEQUENCES OF ALLOWING A UTILITY TO COMMENCE THE RECOVERY OF TRANSITION COSTS NOW?

A If Virginia Power were allowed the opportunity to accelerate recovery of *potentially stranded* costs without concrete evidence that such an extraordinary procedure is needed to prevent undue and irreparable financial harm to the Company, then there is a real likelihood that the utility could over-recover *transition* costs. This would be poor public policy. It would greatly enhance Virginia Power's market power. Market power would be greatly enhanced by having a below-market cost structure, the retention of all of its generation assets and the use of these assets to sell electricity at unregulated prices and the proposed TCC, which would prevent customers from exercising competitive options available under current regulation.

Q WHAT GUIDELINES SHOULD THE COMMISSION FOLLOW IN THIS PROCEEDING TO ASSURE THAT THE TRANSITION TO CUSTOMER CHOICE

OCCURS IN A MANNER THAT MORE EQUITABLY BALANCES THE INTERESTS OF VIRGINIA POWER AND ITS CUSTOMERS?

A The Commission should establish Virginia Power's revenue requirements in this proceeding using traditional cost of service ratemaking practices. Rates should be set in this proceeding to recover Virginia Power's cost of service, no more and no less.

The Commission also should strive to ensure that there will be vigorous competition when customer choice commences. Deregulation of generation is only beneficial to the extent that it is replaced with workable competition, not unregulated monopolies. The Commission, therefore, must assure that no market participant has undue market power. Competitive options, including wholesale competition and cogeneration, should be maintained and expanded during the transition period to create a vibrant competitive generation market when choice is permitted. Certainly, existing choices available to customers should not be eliminated during the transition period. Eliminating existing choice (e.g., rate options, alternative supply options) only moves the industry further away from customer choice.

Q **IS IT NECESSARY TO WAIT UNTIL TRANSITION COSTS ARE FULLY RECOVERED BEFORE ALLOWING CUSTOMER CHOICE?**

A No. If choice does not begin until after recovery of transition costs is concluded, customers will be needlessly delayed access to new and innovative services and alternative suppliers during the transition period. Further, new suppliers will be denied the ability to develop relationships with new customers while the incumbent utilities, such as Virginia Power, are strengthening their customer relationships. Finally, the competitive pressures brought on with the introduction of customer choice can provide even stronger incentives to mitigate transition costs. This was precisely the experience in the natural gas industry.[11]

Q **DOES VIRGINIA POWER'S ALTERNATIVE REGULATORY PLAN MEET THE GUIDELINES AND PRINCIPLES SET FORTH ABOVE?**

A No. Virginia Power's ARP is premature because there is no concrete evidence that extraordinary measures are required to provide for an "orderly" transition to customer choice or to prevent the Company from suffering undue irreparable financial harm. The proposed ARP creates a potential for over-recovering *potential stranded* costs before any date certain is set for customer choice and prior to establishing a workable competitive market. The latter requires determining an appropriate structure and resolving any market power issues that may arise. Virginia Power's Plan also is heavily biased in favor of its shareholders. Virginia Power's ARP should be rejected.

[11]According to the Interstate Natural Gas Association of American, stranded costs in the gas industry turned out to be significantly less than expected, $13.2 billion vs. $44.0 billion, because open access commenced prior to the resolution and recovery of transition costs. See Interstate Natural Gas Association of America Rate and Policy Analysis Department, "Background Report: Comparison of Gas and Electric Industry Restructuring Costs," Report No. 96-2, August 1996.

2. QUANTIFICATION AND RECOVERY OF TRANSITION COSTS

Q **PLEASE SUMMARIZE VIRGINIA POWER'S PROPOSALS WITH RESPECT TO THE QUANTIFICATION AND RECOVERY OF TRANSITION COSTS.**

A Virginia Power is proposing the approval in principle of recovery of 100% of remaining *transition* costs through a TCC. It is also proposing that the Commission approve a methodology for estimating *transition* costs in this proceeding.

Q **SHOULD ANY OF THESE PROPOSALS BE ADOPTED?**

A No. The Commission should reject the Company's proposals. The proposals are premature. As discussed above, retail customer choice is not in place and the Company has provided no showing of need. There is far too little knowledge of the impact of a customer choice regime on the value of the Company's generation assets and NUG contracts to determine whether the proposed TCC would promote, rather than impede, a competitive market or fairly balance the interests of Virginia Power's customers and shareholders. On the other hand, as discussed further, adopting a TCC would be poor policy because:

- Virginia Power has failed to make any distinction between *potentially stranded* costs and *transition* costs;

- Implementing the TCC now would remove any incentive for Virginia Power to mitigate such costs between now and the time retail competition commences;

- The TCC and the potential imposition of exit fees would be anti-competitive; and

- ➢ Full recovery of transition costs would be unfair to consumers because it fails to balance their interests against the interests of the Company. It certainly is not mandated under any regulatory compact.

The methodology for estimating transition costs also should be rejected for the reasons stated in Ms. Iverson's testimony. In addition, the methodology relies on an administrative approach to quantify transition costs. Similar administrative approaches were used to project long-term avoided costs that were then used to price the Company's NUG power purchases. In light of the inability of such methods to accurately foresee major events affecting the future cost of electricity, such as technological changes and the abundance of low-cost natural gas, and its extreme sensitivity to changes in the assumed market prices, the Commission should categorically reject the Company's proposed administrative methodology in this case. If any methodology is to be approved, then it should be based on a market valuation approach. I shall discuss how market-based methodologies are superior to administrative approaches in quantifying transition costs.

Any Quantification Of Transition Costs Is Premature At This Time

Q WHY SHOULD ANY METHODOLOGY FOR QUANTIFYING TRANSITION COSTS NOT BE APPROVED AT THIS TIME?

A First, as previously stated, the Company's definition of *transition* costs includes all costs that may be unrecoverable for whatever reason, including customer choice. *Transition* cost recovery, if done properly, would include only *transition* costs associated with customer choice. Second, the Company admits it is not possible to quantify *transition* costs with precision because market prices cannot be predicted with any accuracy or reliability.[12]

The existence of *transition* costs cannot be established absent an in-depth analysis of the market value of a utility's generation resources *and* specification of a date certain for retail customer choice. Market value cannot be determined without knowing the structure of a competitive market as well as the projected supply and demand for electricity. To my knowledge, none of these parameters is known and measurable today. There is no date certain for retail access. No determination has been made about how retail access will be implemented—immediately for all consumers or as a phase-in. The structure of a competitive market has not been established. Whether and to what extent utilities may exert horizontal and vertical market power and, therefore, influence prices in a competitive market has yet to be considered.

Further, as Ms. Iverson's testimony demonstrates, the Company's methodology is based on very specific, and as yet unknown, parameters about the date certain for retail access, market structure and speculative estimates of future loads and costs. These problems are in addition to the flaws inherent with any administrative determination of future costs, as discussed below.

Absent these critical elements, no determination can be made about an appropriate methodology for quantifying potential *transition* costs.

[12]Rigsby Direct Testimony, Page 46.

Transition Cost Charge

Q WHAT COSTS IS VIRGINIA POWER SEEKING TO RECOVER THROUGH THE TRANSITION COST CHARGE?

A Virginia Power states that it is seeking full recovery of all *transition* costs within seven years of the commencement of retail access. In addition, nuclear decommissioning expenses would be collected through the Transition Cost Charge (TCC) over the remaining life of Virginia Power's nuclear plants.

Q DO THE COSTS VIRGINIA POWER SEEKS TO RECOVER THROUGH THE TRANSITION COST CHARGE SOLELY REFLECT THE IMPACT OF RETAIL COMPETITION?

A No. The methodology it proposes to use to quantify *transition* costs—which it is seeking Commission approval in this proceeding—measures *potentially stranded* costs. As discussed previously, *transition* costs are uneconomic costs arising *solely* because of the transition to retail customer choice. It is wrong to equate *potentially stranded* costs with *transition* costs because the former assumes that all uneconomic costs will be the result of retail customer choice. This ignores the fact that stranded costs may arise for a variety of reasons that are unrelated to the implementation of customer choice. Virginia Power's definition also ignores the fact that uneconomic costs can be either avoided or mitigated. As Ms. Iverson demonstrates, several of the items included in Virginia Power's definition of *transition* costs include costs that are mitigable and avoidable. These items should not be included in the TCC.

Q WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN TRANSITION COSTS AND POTENTIALLY STRANDED COSTS?

A Virginia Power always has faced competition for its generation services from various forms of self-generation. Since at least 1978, moreover, when the Public Utilities Regulatory Policy Act (PURPA) was adopted, Virginia Power has faced competition from NUG suppliers. Generation competition has intensified following the adoption of the Energy Policy Act of 1992. Like most utilities, Virginia Power faces more intense competition in the wholesale market. Suppliers are also positioning themselves for the eventual implementation of retail competition. It is this very type of existing and anticipated competition that has helped to force regulated utilities to cut costs and to offer their customers a broader array of rates and service options, such as RTP. The Commission should not sanction recovery of stranded costs associated with these and other options that are possible in the current environment. To do so would unnecessarily insulate Virginia Power from current operating risks for which investors are being compensated.

Q HAS THIS ISSUE BEEN CONSIDERED IN OTHER FORUMS?

A Yes. In Order No. 888, the Federal Energy Regulatory Commission (FERC) expressly made clear that the opportunity for a utility to recover stranded cost was restricted to situations in which the utility faced the loss of a customer due to new competitive options directly created by the opening of the wholesale market, not options that had previously existed. The FERC stated that it would not "insulate a utility from the normal risks of competition, such as self-generation, cogeneration, or industrial plant closures, that do not arise from the new availability of non-discriminatory open access transmission."[13] The same policy should apply to this case.

Q WHY WOULD IMPLEMENTING A TRANSITION COST CHARGE IN CONCEPT IN THIS PROCEEDING REMOVE VIRGINIA POWER'S INCENTIVE TO MITIGATE TRANSITION COSTS?

A As an example, Virginia Power is presently engaged in negotiations with its NUG suppliers to lessen the impact of these contracts on future expenses.[14] The outcome of these contract negotiations is in doubt and is unlikely to be fully resolved by the time this proceeding concludes. **If the Commission, today, were to provide assurance of full recovery of transition costs commencing at some time in the future, then it would remove Virginia Power's incentive to exert maximum effort to mitigate these potentially significant costs.** Further, if the NUGs are aware that Virginia Power is assured of 100% recovery of costs associated with their contracts, what possible incentive would they have to negotiate reductions in those costs with Virginia Power?

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[13]FERC; Docket Nos. RM95-8-000 and RM 94-7-001, Order No. 888, April 24, 1996, p. 454.

[14]"Report of Virginia Electric and Power Company on Efforts to Restructure Contracts with Non-Utility Generators, Case No. PUE950089," dated June 2, 1997 and attached to Virginia Power's response to Question No. 179 included in the Fifth Set of Interrogatories from the Office of the Attorney General.

Q HOW WOULD THE TRANSITION COST CHARGE BE ANTI-COMPETITIVE?

A The proposed TCC, or in the alternative, an exit fee, would be levied on customers that may opt for self-generation, an option that is available in the present regulatory environment. Besides compensating Virginia Power twice for the risks it incurs today, imposing TCCs on self-generation options would discourage the development of competitive alternatives, contrary to PURPA, the Energy Policy Act of 1992 (EPAct) and FERC Order No. 888, and would unnecessarily enhance Virginia Power's market power. Under Virginia Power's proposed TCC on self-generation options, moreover, it also appears that the customers' motives for electing self-generation options would be scrutinized. Mr. Hilton's testimony states that the TCC would apply "[t]o the extent the implementation of electric industry restructuring and retail competition made it legally possible for a customer to economically discontinue reliance on the system grid for its power supply . . . . "[15] Subjecting a utility customer to an inquiry into whether it has pursued self-generation options as a result of restructuring the electric industry or as a result of other business factors could involve a highly subjective, potentially complex undertaking, and a potentially expensive and burdensome one for the customer. <u>Granting a utility</u> the opportunity to scrutinize its customers' business decisions could open customers to scrutiny in a way that is highly intrusive and anti-competitive.

[15] Hilton testimony, Page 17.

Q HOW WOULD VIRGINIA POWER'S PROPOSALS IN THIS CASE FURTHER ENHANCE ITS MARKET POWER?

A Market power would be enhanced by regulatory policies that prevent or eliminate potential competition or provide for excessive recovery of costs claimed to be "*transition*" costs on the basis of false claims that they are, in fact, a result of a transition to retail competition. As mentioned above, imposing any kind of charge or exit fee on customers who may choose to exercise alternatives that are possible within the current regulatory regime would be anti-competitive. For this reason alone, the proposed TCC should be rejected.

Overcompensating Virginia Power for its transition costs has the potential of transforming the utility into a "super-competitor." A super-competitor is any entity that can profit by selling at below-market prices. By overcompensating Virginia Power for its alleged transition costs, the value of its assets would fall below the value that could be supported in a competitive marketplace. Virginia Power, thus, could utilize the very same assets to sell electricity at below-market prices, thereby stifling competition. Under these circumstances, investors would be compensated twice: once during the recovery of transition costs, and a second time through higher profits from the utilization of the very same assets in a competitive market.

Q CAN THE TRANSITION COST ISSUE BE RESOLVED WITHOUT ADDRESSING AND RESOLVING POTENTIAL MARKET POWER ISSUES?

A No. If retail competition is to benefit all consumers, electric utilities should not be allowed to exert market power. ***Protections against the abuse of vertical and horizontal market power should be implemented to ensure the evolution of sustainable competitive markets.*** Regulators in the United Kingdom (UK) and in the U.S. (such as those in California and Maine) that have initiated the transition to electric competition have recognized that market power is a significant problem in electricity markets, and that market power abuse can lead to market distortions that reduce the benefits to consumers of implementing retail customer choice.

For example, the newly elected Labour Party government in the UK has raised the possibility of requiring asset divestiture by the UK's two largest generation companies to reduce the level of concentration in that country's generation markets.[16] Discussion of such action follows widespread criticism by many in the UK that the country's electric industry restructuring did not produce the expected level of price reductions for consumers due to generation market concentration levels that allowed price leadership and collusion to take place among generation companies, particularly in the bidding procedures for the UK's generation power pool.

In California, the Public Utilities Commission ordered Southern California Edison Company and Pacific Gas and Electric Company, the State's two largest utilities, to divest at least 50% of their fossil-fired generation capacity in order to

[16]The Electricity Daily, Labour Sweep Causes Heartburn, Volume 8, Number 86, May 6, 1997.

mitigate generation market power problems.[17] Southern California Edison Company has, in fact, gone beyond this requirement, and is now in the process of selling off all of its in-state fossil-fired generation. A similar asset sale has already been completed by the New England Electric System (NEES) in the context of this utility's restructuring plan. Other utilities, such as General Public Utilities and Montana Power Company, have announced plans divest themselves of their generation assets and to exit the generation business.

These examples underscore the importance of the market power issue to electric industry restructuring. There are several significant factors that can form barriers to entry into electricity markets and create potential market power problems, including transmission constraints and excessive market concentration levels. To ensure workable competition in the electric industry, Virginia should be prepared to take measures to reduce these barriers.

Q WOULD MARKET POWER CONCERNS BE ALLEVIATED IF THE COMMISSION WERE TO PERMIT FULL RECOVERY OF VIRGINIA POWER'S TRANSITION COSTS?

A No. It should be recognized that incumbent utilities have significant, tactical and strategic advantages over new entrants. First, under present law, only electric

[17] *See* California Public Utilities Commission, Docket Nos. R.94-04-031 and I.94-04-032, Order Instituting Rulemaking and Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Decision No. D.96-01-009, Jan. 1996.

utilities have the right of eminent domain. Second, incumbent utilities have the advantage of name recognition. They also possess extensive and detailed information concerning customers' load profiles and usage characteristics. Continual contact with customers has enabled the utilities the opportunity to better understand customers' wants and needs. Incumbent utilities also have the advantage of scale economies, and they own an extensive infrastructure that supports the production, delivery and sale of electricity to end-users.

Q **WHAT ARE SOME OF THE ADVANTAGES ENJOYED BY INCUMBENT ELECTRIC UTILITIES WITH RESPECT TO THE EXISTING INFRASTRUCTURE?**

A For example, generation plant sites are strategically valuable. First, there are a limited number of sites that can support generation. Most of the existing generation plant sites were chosen because of their proximity to indigenous fuel supplies, load centers or available cooling water, their accessibility to major transportation corridors and the ability to obtain necessary environmental permits. Additionally, incumbent utilities have built, operate and maintain a bulk power system to transmit and deliver power from generating stations to distribution load centers.

Given the existing infrastructure, incumbent utilities have a further advantage of scale economies. That is, generally it would be cheaper to increase capacity at an existing plant site rather than to add a new "green field" site. It may also be much cheaper to repower existing plants than to build totally new capacity.

Q WHAT ARE THE IMPLICATIONS OF THE STRATEGIC AND TACTICAL ADVANTAGES ENJOYED BY INCUMBENT ELECTRIC UTILITIES?

A The implication is that full recovery of potentially stranded costs would allow incumbent electric utilities to gain additional substantial strategic, tactical and cost advantages over their competitors. In other words, it will transform a high-cost, non-competitive supplier into a super-competitor. Such a transformation would not be in the public interest because it would place existing low-cost electric utilities and other market players at a significant competitive disadvantage. In the end, full recovery only will result in less competition.

Q WHAT REGULATORY POLICIES MAY PREVENT A UTILITY FROM UNDULY ENHANCING ITS MARKET POWER DURING THE TRANSITION TO COMPETITION?

A Functional and operational unbundling are essential to ensure a level playing field among competitors in the generation and merchant functions, and to ensure non-discriminatory open access to transmission and distribution facilities for all retail customers. However, taking this step alone has serious shortcomings. Despite the implementation of open access tariffs and utility codes of conduct in FERC Order No. 888, it must be recognized that utility transmission and distribution operations continue to report to the same management and remain owned by the same parent company that in the future will be engaged in competitive activities through affiliated entities. Therefore, functionally unbundled transmission and distribution units have more than just a passing interest in the well-being of their generation and power merchant affiliates.

Possibly the only means of eliminating this conflict of interest is through complete structural separation of the utility's monopoly and competitive functions (i.e., divestiture). In California, the utilities agreed, in principle, to divest a portion of their generation assets as a means of mitigating their market power. Other utilities, like the NEES, have voluntarily divested their generation assets. Besides mitigating market power, this action was a quid pro quo for receiving favorable resolution of the transition cost issue.

Q WHAT GUIDELINES SHOULD BE EMPLOYED TO RESOLVE THE ISSUE OF TRANSITION COSTS IF A LEGITIMATE PROBLEM WERE TO ARISE?

A The Commission should adopt appropriate guidelines to ensure an equitable balancing of the interests of all stakeholders in a contested proceeding.

The utility's claims must be subject to quantification and verification. The analysis must consider the value of resources over their remaining useful lives. Second, because some assets will have a market value higher than their associated net book value (NBV), it is essential to net these above-market assets against the remaining below-market assets.

As mentioned earlier, just because a particular cost is *potentially strandable* does not justify a need to assure recovery when retail competition commences. If the utility has a reasonable opportunity either to mitigate or avoid incurring a *potentially strandable* cost, then no special compensation would be necessary or appropriate. Examples of costs that can be avoided or mitigated include:

- Future administrative and general expenses;
- Revenue-related expenses;
- Fuel supply contracts; and
- Ongoing operation, maintenance and fuel costs associated with resources in which continued operation may not be economic.

For example, Ms. Iverson has determined that Virginia Power has allocated present levels of administrative and general and other corporate overhead expenses in determining the value of its existing resources. There is no evidence to support any stranding of Virginia Power employees as a consequence of customer choice. Further, no such estimate of overhead expenses was reflected in the projected market prices. Thus, Virginia Power's analysis may compare apples to oranges.

As previously noted, it is also reasonable to conclude that utilities were fully aware of impending competition in retail electricity markets by no later than October 1992, the date of enactment of the EPAct. The EPAct established a national policy of expanding competition in the electric industry. Utility shareholders have had more than adequate warning by that time that any new investments could be rendered uneconomic by increased competition in the industry. Thus, uneconomic investments made after October 1992 should be expressly excluded from consideration. Similarly, any claims of *transition* cost recovery associated with the advent of wholesale competition in electricity markets should be excluded from consideration.

Finally, as discussed earlier, costs that are *strandable* in the current environment should not be included in any transition charge that might ultimately be adopted.

Thus, it is clear that the application of these criteria would limit retail transition cost recovery to only those sunk, fixed generation-related utility investments that would become uneconomic solely due to retail customer choice. They also would preclude defining utility *transition* costs based on any and all revenues lost by the utility due to a retail customer's decision to select an alternative generation provider. There is no justification whatsoever to equate retail transition costs with lost revenues because not all costs included in present and future rates will be unrecoverable in a post-regulatory environment.

Full Recovery Of Transition Costs Is Not
<u>Sanctioned Under Any So-Called Regulatory Compact</u>

Q IS IT YOUR UNDERSTANDING THAT THE A "REGULATORY COMPACT" MANDATES THE OPPORTUNITY FOR RECOVERY OF AND A RETURN ON ALL PRUDENTLY INCURRED COSTS FROM CUSTOMERS UNDER ANY AND ALL CIRCUMSTANCES?

A No. There is considerable regulatory precedent for the concept of cost sharing between customers and investors, even when the decision to make a particular investment was prudent. For example, in ruling that the unamortized losses associated with three abandoned nuclear plants, Surry Units 3 and 4 and North Anna Unit 4, should not be included in the rate base, this Commission stated that:

> Traditional business practice, as well as economic theory, demands that the ratepayers not bear this entire investment burden. The fact that VEPCO is a regulated monopoly does not mean, *and has never meant*, that the ratepayer rather than the investor must bear the investment risks.[18]

The Commission further articulated this policy in a subsequent decision:

> ...the Commission was at pains to carefully balance the interests of shareholders and ratepayers with regard to these [nuclear plant] cancellations. The Commission recognized that someone would have to pay for the loss of these projects, which were originally intended to benefit both shareholders and ratepayers, and that it was not fair to insulate either group entirely from the financial effects of the abandonment.
>
> The balance which the Commission struck was that, although the investors would be allowed to recover the actual <u>cost</u> of the projects from the ratepayers over a reasonable period of time, the ratepayers would not have to pay, and the investors would therefore lose, any <u>return</u> on that cost.[19]

Many other state regulatory commissions have approved similar cost sharing arrangements by allowing the recovery of plant abandonment costs but denying a return on the unamortized balance.[20]

[18]Virginia State Corporation Commission, "Application of Virginia Electric and Power Company To Revise its tariffs, Final Order," Case No. PUE810025, August 24, 1981. Emphasis added.

[19]Virginia State Corporation Commission, "Application of Virginia Electric and Power Company To Revise its Tariffs, Final Order," Case No. PUE840071, May 16, 1986.

[20]NARUC, <u>Utility Regulatory Policy In The United States and Canada</u>, Compilation 1992-1993, Table 34.

Recently, in a case in which I was involved, the Public Utility Commission of Texas (PUCT) adopted a similar cost sharing approach in determining that utilities were not entitled to full recovery of their "excess cost over market" (or ECOM) associated with an operating nuclear plant:

> In its mandated role as a substitute for competition, the Commission pursuant to §2.203 [of the Public Utility Regulatory Act] must in each rate proceeding set overall revenues at a level to provide a reasonable opportunity to earn a reasonable return on invested capital used and <u>useful</u> in rendering service. ***ECOM is inherently economically and technologically unuseful, or at a minimum less useful in rendering service.*** Under the "used" standard, the Commission has exercised its authority to balance equities by allowing recovery of capital costs by eliminating or reducing the return on assets previously found prudent, but no longer used. The same rationale may be consistently applied when assets are unuseful. [bold emphasis added][21]

Thus, it is clear that shareholders have always had to bear investment risk, such as an abandoned plant or a facility that is rendered uneconomic.

Q **VIRGINIA POWER CLAIMS THAT FULL RECOVERY OF STRANDED COSTS IS ESSENTIAL TO MAINTAINING ITS FINANCIAL INTEGRITY. HOW DO YOU RESPOND TO THIS ARGUMENT?**

A This argument rests entirely on speculation. Beyond the speculativeness of the "transition costs" themselves, Virginia Power has not even attempted to show the impact of competition on its financial integrity. The aggressive overseas and domestic investment activity of many U.S. electric utilities, including Dominion

[21] Public Utility Commission of Texas, "Application of Central Power and Light Company for Authority to Change Rates, Order on Rehearing," Docket No. 14965, Page 2.

Resources, Virginia Power's parent company, belies current assertions about threatened financial viability. Rather than being needed to stave off utility bankruptcies, full transition cost recovery would create a source of risk free cash that Virginia Power could use to compete against other suppliers.

Virginia's electricity consumers should not be required to subsidize the unregulated business ventures through claimed "transition cost" recovery.

Equitable Sharing Of Transition Costs

Q **ARE THERE LEGITIMATE POLICY REASONS FOR REQUIRING THAT THE BURDEN OF ANY RECOVERY OF TRANSITION COSTS BE SHARED BETWEEN CUSTOMERS AND REGULATED UTILITIES?**

A Yes. Electric utilities have an obligation and a responsibility to mitigate *transition* costs. If utility shareholders are required to bear some risk associated with *transition* cost recovery, they will have a strong incentive to reduce the level of these costs, which will inure to the benefit of both customers and shareholders.

Q **DO YOU BELIEVE THAT THE SHARING OF TRANSITION COSTS BETWEEN CUSTOMERS AND INVESTORS WOULD BE CONTRARY TO A "REGULATORY COMPACT"?**

A No. Regulators today are facing a dilemma with respect to so-called *transition* costs that is similar to the dilemma they faced in the 1970s and 1980s when numerous electric utilities canceled major construction projects and requested full-cost recovery from customers. The response then was to require cost sharing as a means of balancing the interests of customers and investors. Even when the decision to make a particular investment was prudent, regulators allowed utilities to recover plant abandonment costs, but they denied a return on the unamortized balance. This was precisely the outcome that the PUCT reached in denying full recovery of transition costs.

Nothing has changed that would affect the requirement that regulators must continually balance customers' and investors' interests in deciding the issues arising in ratemaking and other proceedings. Thus, mandatory recovery of all *transition* costs from customers would be fundamentally at odds with this long-standing regulatory precedent. Based on the foregoing, the equitable sharing of *transition* costs between customers and shareholders would provide a reasonable balance of the interests of both investors and consumers in the transition to retail competition.

<u>Administrative vs. Market-Based Approaches</u>

Q IN HER TESTIMONY, MS. IVERSON CHARACTERIZED VIRGINIA POWER'S METHOD OF QUANTIFYING STRANDED COSTS AS AN ADMINISTRATIVE APPROACH. SHOULD THIS COMMISSION SANCTION AN ADMINISTRATIVE QUANTIFICATION OF TRANSITION COSTS?

A No. The quantification of transition costs necessarily depends on the expected level of competitive market prices for electricity and the future operating costs of existing generation assets. These parameters are difficult to predict even when such variables as a date certain for retail access, market structure and market power issues have been determined. The difficulty in accurately forecasting avoided costs in the mid-1980's further demonstrates the folly of such an administrative approach to quantification.

Administrative determinations of transition costs are necessarily judgmental and will be subject to considerable scrutiny in regulatory proceedings such as this case. The fact that any forecast of market value will be wrong will, in turn, spawn a new round of regulatory proceedings to "true-up" the level of transition cost recovery based on new evidence regarding market prices. This highly controversial and highly politicized process would result in a large and wasteful expenditure of resources by industry stakeholders. The Commission should reject this approach.

Q WHAT APPROACH SHOULD BE USED TO QUANTIFY TRANSITION COSTS?

A To the extent possible, *transition* costs should be quantified using objective market valuations of generation assets such as asset sales, stock valuations, auctions, or similar means to establish the appropriate level of transition costs. Market mechanisms provide an objective measure of the market value of assets, and the use of such mechanisms can avert the need for prolonged legal proceedings to establish speculative, administratively determined market price levels to quantify *transition* costs.

Q WHAT ARE SOME OF THE WAYS THAT THE MARKET CAN DETERMINE THE VALUE OF A UTILITY'S RESOURCES?

A One example would be to quantify *transition* costs through arms-length, competitive asset sales to third parties. Under this approach, the *transition* costs associated with the sold assets would be determined by offsetting the sale price of the assets against their NBV. Such asset sales could be phased-in over time to ensure that they are not sold at "fire sale" prices. As previously stated, this approach was successfully implemented by NEES in its recent divestiture of all of its generation resources, which also included the assumption of purchased power contracts. The net proceeds from the sales will be used to reduce the recovery of transition costs from NEES' customers.[22]

Alternatively, transition costs may be quantified through stock valuations if the incumbent utility spins-off its generation assets to a separate, publicly traded affiliated or non-affiliated corporation. Under this method, the market price of the assets would be determined by using the average daily closing price of the stand-alone generation company's common stock over a specified period of time. The utility's transition costs then would be determined by offsetting this stock price against the NBV of the utility's generation assets.

[22]"NEES' Stranded-Cost Charges Expected to Drop as USGEN Buys Generating Assets," Industrial Energy Bulletin, July 22, 1997, p. 4.

Q WHAT ARE THE ADVANTAGES OF A MARKET-BASED QUANTIFICATION OF TRANSITION COSTS?

A First and foremost, market based approaches avoid the guesswork inherent in administrative quantifications. Second, a market approach necessarily would require some degree of separation of existing generation-related assets in the case of a spin-off or divestiture in the case of an asset sale. Either a separation or divestiture would mitigate potential market power concerns. Thus, two key issues—the quantification of transition cost and the mitigation of market power—can be resolved simultaneously .

Finally, the California and New England asset sales and the announcement of over 13,000 megawatts of "merchant" power plants are evidence of a vibrant generation market. [23] (A merchant plant is generation in which the capacity is not already committed to a purchaser at the time of construction.) These experiences, coupled with the resolution of potential market power problem, should alleviate concerns that existing assets would not be properly valued.

[23] "The Electricity Daily," September 2, 1997.

3. UNBUNDLING OF RATES

Q VIRGINIA POWER HAS FILED TWO SETS OF ILLUSTRATIVE UNBUNDLED TARIFFS IN THIS PROCEEDING. HAVE YOU REVIEWED THESE TARIFFS?

A Yes. The first set of unbundled tariffs (Exhibit No. AGE-___, Schedule 7) separates the rates and charges into customer, demand and energy components based on rate of return parity. The demand components were further separated between production, transmission and distribution functions.

The second set of tariffs (Exhibit No. AGE-___, Schedule 9) is similar to the first set, except for the additions of the TCC and Ancillary Service charges to replace the Production and Energy charges. Virginia Power represents that the Ancillary Service charges were based on the same charges that have been approved by the FERC, in Docket No. OA97-52-000.

Q SHOULD THE COMMISSION REQUIRE VIRGINIA POWER TO REQUIRE UNBUNDLING OF ITS TARIFFS IN THIS PROCEEDING?

A Yes. Virginia Power should be required to unbundle its existing rates in this proceeding for informational purposes. I am not recommending that any rates should necessarily be changed in total, unless the Commission were to authorize a general rate change. Unbundling will provide a first step in the transition to customer choice because customers now will be aware that their electricity service actually is comprised of many individual services. These individual services include generation, transmission and distribution wires (i.e., capacity-related services), metering and billing (i.e., customer-related services), and fuel and variable operating and maintenance expenses (i.e., energy-related services). In addition, supporting the generation and delivery functions are the various Ancillary Services.

When customer choice is implemented, customers will have an opportunity to purchase generation services from suppliers other than Virginia Power. Certain delivery and ancillary services also may be required. However, every customer may not require precisely the same services. Some industrial customers, for example, may utilize self-generation or third party providers to follow their load or to provide reactive power. These customers may not require Virginia Power to provide generation, load following or reactive power, and they should not have to pay for them.

Further, it is possible that many of the unbundled services will be provided competitively by multiple suppliers, in addition to Virginia Power. For example, scheduling, system and control and dispatch, regulation and frequency response, spinning reserve, supplemental reserve and metering and billing services could be competitively sourced.

Q WHY ELSE SHOULD THE COMMISSION REQUIRE VIRGINIA POWER TO FULLY UNBUNDLE ITS RATES?

A Requiring all electric suppliers to unbundle rates into discrete components will enable prices for each competitive service to become more transparent in the marketplace. Price transparency is an essential ingredient of a competitive market. For those services which will remain natural monopolies or where a competitive market has not developed, the unbundled prices would reflect the actual cost of providing each service. Cost-based rates will send the appropriate price signals to customers and prevent suppliers from using their monopoly services to subsidize competitive services as a means of gaining market share.

Thus, rate unbundling is essential to achieving and maintaining a fully competitive market that will allow customers to choose appropriate service options.

Finally, by minimizing opportunities to shift costs between competitive and regulated operations, unbundling also will help to mitigate attempts by electric utilities to exert market power.

Q SHOULD ANY OTHER DISCRETE SERVICES BE UNBUNDLED?

A Yes. The illustrative tariffs presented by Mr. Evans recognize, for example, that Power Supply should be unbundled into Production and Transmission. However, all services which will not necessarily remain natural monopolies should be unbundled and separately priced. Examples of these services include metering, billing, and customer information services. Explicitly unbundling these services will allow competing suppliers to provide them directly to customers.

Further, decommissioning costs, taxes and other governmental levies, and public policy programs should be separately stated in the unbundled tariffs. This will provide appropriate information for customers to better understand all of the factors that comprise the cost of electricity. It is possible that metering and billing services eventually could be competitively sourced.

For these reasons, in addition to the informational unbundling of rates in this proceeding into Production, Transmission, Distribution, and Energy, the Commission should order Virginia Power to file—within 60 days of the Commission's final order in this case—an application to further unbundle customer costs into metering and billing components and to separately price decommissioning costs, taxes and other governmental levies, and public policy programs.

Q DO YOU HAVE ADDITIONAL POLICY CONCERNS REGARDING THE ILLUSTRATIVE TARIFFS FILED BY VIRGINIA POWER?

A Yes. In his testimony, Mr. Evans has raised the possibility that changes could be made to the unbundled rates before actual billing could occur.[24] He cites the FERC's Order of February 25, 1997, in Docket No. ER97-960-000, in which a proposal by Washington Water Power Company (WWP) to set the transmission component of an unbundled retail tariff at the level currently reflected in WWP's

[24] Evans testimony at Page 25.

retail rates was denied. Specifically, the FERC is requiring that the transmission unbundled rate be set at a level consistent with WWP's Open Access Transmission Tariff (OATT) filed in compliance with Order No. 888.

Q WHAT ARE THE IMPLICATIONS OF FERC'S ACTIONS FOR THIS PROCEEDING

A Retail competition is not being implemented as part of this proceeding. Rather, VCFUR only is requesting that Virginia Power be required to unbundle its tariffs for informational purposes. Thus, the Commission need not address, in this proceeding, the issues raised by the WWP case.

However, Mr. Evans' testimony on this topic highlights an issue that will need to be addressed as part of any subsequent implementation of retail customer choice. We estimate that using Virginia Power's OATT would cause Virginia Power's transmission revenue requirements to increase by $12.4 million per year relative to its test year embedded transmission cost of service. In other words, unless further actions were taken, Virginia Power would receive a $12.4 million per year windfall if the FERC requires the use of its Order 888 OATT charges for determining the unbundled cost of providing retail transmission service.

Q WHAT IMPACT DOES THIS ISSUE HAVE ON VIRGINIA POWER'S TRANSITION COST PROPOSALS?

A Mr. Evans' testimony on this issue provides another example of why Virginia Power's Transition Cost proposals are untimely and should be rejected in this proceeding. For example, one way to address this issue—to prevent Virginia Power from benefiting from a $12.4 million windfall—would be to allow Virginia Power to apply the FERC-approved firm transmission rates, but require that a portion of the revenues be used to offset other non-transmission related revenue requirements. Because all customers require the use of the transmission system, the most appropriate options would be to require an offsetting reduction to the unbundled Production charge. If the Commission were to impose a TCC once retail customer choice is implemented, then this charge should also be reduced to offset the corresponding increase in the unbundled retail Transmission charge.

Consequently, the resolution of this issue in a subsequent proceeding will impact any TCC mechanism. This further illustrates why it is inappropriate to establish a TCC in a vacuum, as requested by Virginia Power in this case.

4. CLASS REVENUE DISTRIBUTION

Q **IF BASE RATES ARE TO BE CHANGED IN THIS PROCEEDING, HAVE YOU PREPARED AN EXHIBIT TO SHOW HOW THE CHANGE WOULD BE DISTRIBUTED AMONG THE VARIOUS CLASSES, CONSISTENT WITH THE COMMISSION'S REVENUE DISTRIBUTION GUIDELINES?**

A Yes. The illustration is shown in Exhibit ___(JP-1). It is based on the Company's Average and Excess (A&E) cost of service study. For illustrative purposes, I have assumed a $200 million reduction.

Q **WHAT REVENUE DISTRIBUTION GUIDELINES HAS THE COMMISSION ADOPTED IN PRIOR CASES?**

A The Commission's long-standing policy has been to move each class toward parity, to within a ± 10% bandwidth of the overall jurisdictional rate of return, while also recognizing the need to apply gradualism to avert rate shock, by limiting the percentage change to a maximum of 150% of the overall percentage change in rates.[25]

Q **WHAT IS THE RESULT OF APPLYING THESE GUIDELINES?**

A Page 1 of Exhibit____ (JP-1) shows the resulting base revenue distribution by customer class, while Page 2 compares the cost of service study results before and

[25]State Corporation Commission, Final Order, Application of Virginia Electric and Power Company For a general increase in rates, Case No. PUE920041, Pages 19 and 20; February 3, 1994.

after the rate reduction using the Commission's revenue distribution guidelines. In order to move all of the major classes uniformly closer to parity and because VCFUR is recommending a significant rate reduction, rather than a rate increase, I adjusted the gradualism constraint to 160% of the overall percentage change in rates.

As can be seen on Page 1, the reduction would be constrained for the GS-1, Churches and Outdoor Lighting classes. However, all of the major classes would move approximately 25% toward parity, as defined by the Commission.

5. REAL TIME PRICING

Q IS THE CONTINUED DEVELOPMENT AND EVOLUTION OF THE COMPANY'S REAL TIME PRICING PROGRAM CONSISTENT WITH THE TRANSITION TO RETAIL CUSTOMER CHOICE?

A Yes. Real Time Pricing (RTP) is a precursor to "spot-market" pricing which is likely to occur in a fully competitive electric utility industry. Thus, RTP will help prepare both Virginia Power and its customers for competition and retail customer choice.

Q IS REAL TIME PRICING EQUIVALENT TO SPOT-MARKET PRICING?

A No. Although similar in structure, RTP is not equivalent to spot-market pricing because the hourly spot prices under RTP are based on a single generation supplier (Virginia Power, in this case). By contrast, a competitive spot-market will require the interaction of many generation sellers and many buyers, irrespective of ownership or customer type, throughout the interconnected grid. Further, Virginia Power's Schedule RTP limits the eligible load of its RTP customers to a maximum of 20% for RTP. In a fully competitive, customer choice environment, customers could choose to subject any portion, or the entirety, of their load to spot-market pricing. The customer also would be able to enter into bilateral contracts with one or more generation suppliers. Thus, Schedule RTP may provide customers with limited "virtual" direct access, but it is certainly not a substitute for customer choice.

Q **SHOULD VIRGINIA POWER PROVIDE AN ADDITIONAL REAL TIME PRICING OPTION?**

A Yes. The Company should be required to develop a second RTP rate schedule, in addition to the current experimental Schedule RTP. This second RTP option should be based upon "hour-ahead" pricing.

The hourly prices in Schedule RTP are presently developed on a "day-ahead" basis. Customers are provided firm hourly RTP energy charges by 5:00 p.m. on the day prior to actual consumption. Further, these prices are not subject to true-up or adjustments should the Company's actual system lambda vary from the original projection.

Although day-ahead pricing is a significant improvement over the more traditional time of use (TOU) tariffs, it is probable that the actual hourly prices will be different because day-ahead loads may be higher or lower than projected (due to ever-changing weather conditions), or generating units may be unexpectedly forced out of service. The hourly energy price also would vary significantly if the actual load in a particular hour reached or exceeded 90% of the Virginia Power adjusted annual peak load forecast, because this is when either the Generation Cost adder (GCA) or the Transmission Capacity adder (TCA) would be applicable. The end result would be dramatic change in the level of the hourly RTP prices relative to the day-ahead forecast.

Thus, the price signals under Schedule RTP could be improved dramatically if the Company were to begin offering "hour-ahead" in addition to day-ahead pricing. With hour-ahead pricing, customers still would be given day-ahead forecasts, but these hourly prices would continually be updated as conditions warrant. The price would not be firm until one hour and five minutes prior to the commencement of the hour in question. For example, a price which is applicable for the hour ending at 5:00 p.m. (4:00 p.m. to 5:00 p.m.) would become firm at 2:55 p.m. This would give customers some opportunity to adjust operations (e.g., between 2:55 p.m. and 4:00 p.m.) to respond to the pricing signal.[26] The advantage of hourly pricing, thus, is that it will provide more accurate price signals, and therefore, an opportunity for customers to respond to unexpected changes in system loads and costs on a more dynamic, real time basis.

Q **WOULD A REAL TIME PRICING HOUR-AHEAD PROGRAM BE OF INTEREST TO ALL COMMERCIAL AND INDUSTRIAL CUSTOMERS?**

A No. RTP may not be suitable for all customers. For example, not all customers have equal ability to respond to changing hourly prices. Even customers who are able to respond to changes in hourly prices may choose not to participate in RTP because of the added risks. For example, Schedule RTP customers may have to curtail loads to the applicable baseline levels when the Company is facing an extremely critical system operation situation. Schedule RTP customers also bear considerable price risk; that is, unlike regular tariff customer, their prices will change from hour-to-hour, and these changes immediately affect their cost of electricity.

[26]By providing continuous updates of hourly prices, Virginia Power will have given the customer advanced warning that hourly prices later in the day could change dramatically. This would give the customer an opportunity to adjust or fine tune schedules to respond to the high prices, if possible.

Both sets of risks are unique to Schedule RTP, and they are not risks that non-RTP customers are required to bear. These curtailment and price risks would be further accentuated under an hour-ahead program.

Q ISN'T THE REAL TIME PRICING OPTION VOLUNTARY?

A Yes. The voluntary nature of the rate, however, does not change the risks that Schedule RTP customers are required to assume. Further, some customers will be able to manage risks better than others.

Q IS VIRGINIA POWER IN THE PROCESS OF DEVELOPING AN HOUR-AHEAD REAL TIME PRICING PROGRAM?

A Yes. The Company is considering the design of an hour-ahead RTP program.[27] The Company cites the ability to provide a more accurate price signal as one of the objectives of an hour-ahead program. It also suggests several other objectives, such as variable GCAs and TCAs to prevent over or under-recovering marginal costs and the ability to impose curtailments during unexpected emergency events, such as the event that occurred on January 19, 1994 when the Company initiated rotating black-outs.

The Commission should require Virginia Power, within 60 days of a final order in this case, to file an application for an additional RTP schedule that is based

[27]See Virginia Power report entitled "Improved Price Signals for Each Customer Class," Case No. PUE960296.

upon hour-ahead pricing. The Company also should be encouraged to continue its efforts to develop an hour-ahead program and to be involved in this process.

Q ARE THERE ANY OTHER RISKS UNIQUE TO SCHEDULE REAL TIME PRICING?

A Yes. Customers that subject up to 20% of their existing loads to RTP are required to sign five-year contracts for their entire loads. In light of the increasingly rapid changes occurring in the electricity industry, a five-year commitment may be viewed as too risky by some customers. Further, the limitation that Schedule RTP loads not exceed 20% of the customer's total load may further limit opportunities for customers to utilize self-generation to displace loads that are priced under the Company's Large General Service Tariff.

For example, a non-generating customer having a 50 megawatt total load could purchase up to 10 megawatts of load under Schedule RTP. However, any significant and permanent change in electric load, such as installing base load generation to displace the remaining 40 megawatts of load being purchased under the Large General Service Tariff, would necessitate a modification to the amount of load priced under Schedule RTP. The end result could be to deter the customer from the more economical self-generation option. This provision is an impediment to self-generation. It would not be in the public interest to allow the Company to impose terms and conditions that may impede the development of competitive supply options during the transition to customer choice.

Q SHOULD ANY MODIFICATIONS BE MADE TO THE EXISTING SCHEDULE REAL TIME PRICING?

A Yes. First, Virginia Power should explore the option of expanding the current Schedule RTP to encompass more than 20% of a customer's historical load. As I discussed earlier, Schedule RTP is a precursor to spot market pricing and customer choice. An expanded Schedule RTP will further assist in the transition to customer choice. Virginia Power should, at tne conclusion of this case, file a report with the Commission on the option of expanding Schedule RTP to include greater than 20% of a customer's historical load.

Second, the Commission should order the Company to eliminate immediately the restrictions on self-generation in Schedule RTP. As I discussed above, Schedule RTP effectively restricts the construction of self-generation—by mandating the displacement of any existing RTP load. It is not in the public interest to permit Virginia Power to obstruct the development of competitive supply options in this manner.

Finally, further consideration should be made to ensure that the hourly prices accurately reflect a competitive market. Presently, the prices under Schedule RTP are based on Virginia Power's hourly system lambda. These prices are further increased by $6 per MWH and, in certain hours, by the GCA and TCA. The system lambda typically reflects the incremental cost of generation for a particular utility. To the extent that purchased power is not included in system lambda, the full effect of the increasingly competitive wholesale market is not being reflected in the hourly prices. Similarly, to the extent that Virginia Power's system is experiencing congestion, either generation or transmission, but neighboring systems are not, its hourly real time price may not accurately reflect market conditions.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING REAL TIME PRICING.

A The Commission should order the Company to make the following filings no later than 60 days from the Commission's final order in this case: (1) an application to implement a second RTP rate schedule based on hour-ahead pricing; and (2) an application addressing the expansion of the existing Schedule RTP to include greater than 20% of a customer's historical load.

In addition, the Commission should order the Company to remove, from existing Schedule RTP, the restrictions on the construction of self-generation. Finally, I recommend that Virginia Power be required to investigate whether its Schedule RTP prices reasonably comport with actual market conditions.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

#415318

Qualifications of Jeffry Pollock

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock. My business mailing address is P. O. Box 412000, St. Louis, Missouri 63141-2000.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June, 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. Drazen Brubaker & Associates, Inc. (DBA) was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. Brubaker & Associates, Inc. (BAI) was formed in April, 1995. In the last five years, BAI and its predecessor firm has participated in more than 700 regulatory proceeding in forty states and Canada.

During my tenure at both DBA and BAI, I have prepared numerous financial and economic studies of investor-owned, cooperative and municipal utilities, including revenue requirements, cost of service studies, rate design, site evaluations and service contracts. Recent engagements have included advising clients on electric restructuring issues, developing responses to utility requests for proposals (RFPs), and managing RFPs for clients. I am also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over twenty states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

VIRGINIA ELECTRIC AND POWER COMPANY

Illustration of the Commission's Revenue Distribution Guidelines Assuming a $200 Million Revenue Reduction Test Year Ended December 31, 1996

Line	Customer Class	Present Rate Revenue (000) (1)	Revenue Adjustment Amount (000) (2)	Revenue Adjustment Percent (3)	Index (4)
1	Residential	$1,827,133	($102,445)	-5.6%	95
2	GS-1	221,500	(20,900)	-9.4%	160
3	GS-2	572,344	(30,160)	-5.3%	90
4	GS-3	467,785	(32,310)	-6.9%	117
5	GS-4	294,134	(12,450)	-4.2%	72
6	Total Churches	6,680	(630)	-9.4%	160
7	Outdoor Lighting	11,676	(1,105)	-9.5%	161
8	Virginia Jurisdictional	$3,401,252	($200,000)	-5.9%	100

VIRGINIA ELECTRIC AND POWER COMPANY

Summary of the Class Cost of Service Study
Before and After a $200 Million Revenue Reduction
Using the Commission's Revenue Distribution Guidelines
Average and Excess Method; Fully Adjusted
Test Year Ended December 31, 1996

		Rate of Return		Index		
Line	Customer Class	Before Reduction (1)	After Reduction (2)	Before Reduction (3)	After Reduction (4)	ROR Movement (5)
1	Residential	8.40%	6.94%	93	95	24.9%
2	GS-1	12.52%	9.43%	139	129	25.5%
3	GS-2	8.85%	7.21%	98	99	25.5%
4	GS-3	10.66%	8.30%	118	114	26.1%
5	GS-4	8.51%	7.00%	94	96	24.8%
6	Total Churches	15.92%	12.50%	177	171	7.5%
7	Outdoor Lighting	12.04%	9.51%	134	130	10.6%
8	Virginia Jurisdictional	9.01%	7.31%	100	100	n/m